Northpower

Pricing Methodology

1 April 2021 – 31 March 2022

1 Introduction

Northpower owns and operates the electricity distribution network covering the Whangārei and Kaipara regions, delivering electricity to more than 60,000 homes and businesses. The network covers a wide geographic area from Pouto in the south to Bland Bay in the north, and includes Whangārei city and Dargaville township, as well as extensive rural areas.

There are six major industrial consumers on our network, whom collectively consume approximately 47% of the electricity conveyed across the network. In addition there are approximately:

- 49,000 residential dwellings
- 5,000 farm related connections (sheds, pumps, farm utilities)
- 2,500 commercial premises (shops, offices, workshops)

We recover the cost of owning and operating the network through a combination of standard (i.e. published) and non-standard prices for electricity lines services, and capital contributions for new connections. This document describes our methodology for setting our prices for electricity lines services.

We are wholly owned by the Northpower Electric Power Trust, which is a consumer trust. As such, we are effectively owned by our consumers.

2 Regulatory Context

2.1 Commerce Act

The Commerce Commission ("Commission") regulates markets where competition is limited, including electricity distribution services, under the Commerce Act 1986 ("the Act"). Under the Act, an electricity distribution business ("EDB") can be subject to information disclosure regulation, or both information disclosure and price-quality regulation.

Price-quality Regulation

Price-quality regulation is the process whereby the Commission sets the Maximum Allowable Revenue that an EDB may receive from distribution prices. As Northpower meets the definition of an exempt consumer owned EDB (because it is owned by consumers via a consumer trust, trustees are elected, over 90% of consumers benefit from distributions, and there are less than 150,000 ICPs), it is not subject to price-quality regulation.

Information Disclosure Regulation

Information disclosure regulation is the process whereby EDBs are required to publish information about their performance. The purpose of this regulation is to ensure that information is available to interested persons to assess whether the purpose of Part 4 of the Act is being met. The requirements are set out in the Electricity Distribution Information Disclosure Determination 2012 (including subsequent amendments) ("EDIDD").

This document contains the information required to be disclosed in accordance with clauses 2.4.1 to 2.4.5 of the EDIDD.

2.2 Electricity Authority

We have developed our prices with reference to the Electricity Authority's Pricing Principles ("Pricing Principles") and its August 2019 Guidance Note. The purpose of the Pricing Principles is to ensure prices are based on a well-defined, clearly explained, and economically rational methodology. While the Pricing Principles are voluntary, the Disclosure Determination requires each EDB to either demonstrate consistency with the Pricing Principles or explain the reasons for any inconsistency.

Appendix 3 sets out the Pricing Principles and comments on the extent to which our Pricing Methodology is consistent with them.

2.3 Low Fixed Charge Regulations

We are subject to the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 ("Low Fixed Charge Regulations"). These regulations require us to offer residential consumers a price option at their primary place of residence with a fixed price of no more than 15c per day (excluding GST) and where the sum of the annual fixed and volume charges on that price option equals any other permanent place of residence price option for consumers using 8,000kWh per annum.

2.4 Electricity Code

We have developed our policies and procedures for installation and connection of distributed generation in accordance with the requirements of Part 6 (Connection of Distributed Generation) of the Electricity Industry Participation Code 2010 ("the Code").

3 Pricing Strategy

Our pricing strategy is to transition network pricing to be appropriately cost reflective and responsive to the evolving market and the changing ways that consumers are using electricity.

Electricity networks are like roads in that they can become congested at peak times of the day. Cost reflective pricing uses price signals to demonstrate when there is capacity in our network (through lower prices), and when the network is more congested (through higher prices).

Consuming more electricity at peak times may mean that we might need to incur cost to increase the capacity of our network in the future.

Emerging technology such as electric vehicles, solar panels, and batteries are changing how we consume, generate, and manage our electricity. We think it is important that pricing evolves to encourage efficient use of the network to minimise the cost of capacity increases, reduce prices for consumers in the long term and to ensure fair outcomes for all consumers on our network.

This strategy will broadly result in fixed prices increasing, variable prices decreasing, and differentiated pricing being available based on the time of day.

3.1 Network Capacity

Pricing can have a role in alleviating congestion and capacity constraints on a distribution network through sending appropriate price signals. For the majority of our network there are no capacity constraints. However, we do have some emerging challenges.

- Helena Bay and surrounding areas sometimes experience congestion issues around holiday periods due to the high proportion of holiday homes and associated influx of holiday makers, leading to additional network demand for short periods of time. This is compounded by the remote location, meaning it is a significant distance from the nearest substation.

- Mangawhai has historically been fed from a single 33kV circuit into the area, with backfeeding capability via the 11kV network. To meet significant growth expected in the next 10 years we are investing in a second 33kV circuit, and a number of smaller upgrades. There is a risk that if growth exceeds that forecasted, there may be insufficient capacity to meet demand. The "but for" approach incorporated into our Capital Contributions policy provides a price signal to indicate when it may be more efficient to connect in other locations on the network, where there is existing unutilised capacity.

- A large scale distributed generator has applied to connect to the network in the Dargaville region. The scale of the proposed generation is such that the entire export capacity of the 50kV lines into the Dargaville region is now allocated to that project, and as such any further large scale distributed generation applications in that part of the network would need to contribute to upgrades on a "but for" basis.

- There continues to be an uplift in enquiry around large scale distributed generation on the network. In some cases the scale of these enquiries mean that, if any of the projects were to go ahead, they would effectively take up all of the existing capacity to inject generation in that part of the network, requiring future connecting parties to pay for network upgrades on a "but for" basis.

The Electricity Code limits EDBs to recovering only their incremental costs in relation to distributed generation, and as such new distributed generators are generally required to build and vest any incremental assets or network upgrades required to connect their proposed plant.

As part of our network planning processes, we now actively consider non-network alternative options to address system constraints. We consider if local generation or balancing options may be viable, and if contracted demand response schemes may be able to defer or avoid asset based solutions. In the current energy environment, the applicability of non-network solutions is limited for very high load situations, however this situation may change in future as practical options emerge in the market.

Congestion is likely to be an emerging issue more generally on our network into the future depending on the changing energy requirements of consumers and large scale distributed generation. Growth in our region tends to be outward rather than through increasing density, and as such new assets are required to extend the geographical reach of the network. This has the effect of increasing the capacity of the network in the places it is needed, noting increases in substation and 11kV capacity can be required.

Growth in places where the network already exists such as on the outskirts of Whangārei could potentially be absorbed through active network management once constraints are reached. Also electrification such as widespread adoption of electric vehicles, commercial transport, and industrial process heat could also increase demand for electricity, and create congestion.

In terms of these more general trends, we consider it important to get pricing structures in place now that encourage consumers to think about where prices are going in the long term, and send appropriate signals as consumers consider making long term investment decisions in relation to distributed generation, storage, electric vehicles, heating, and other appliances.

3.2 Smart Meter uptake

Cost reflective pricing is heavily reliant on smart meter uptake, enabling half hour consumption reads to calculate consumers' electricity consumption in different ways, such as by peak, shoulder, and off-peak periods to facilitate Time of Use (ToU) billing. The meters also need to be able to communicate reliably and consistently.

We currently have 88% of connected ICPs on our network with smart metering installed and 83% are marked as communicating in the Registry. Both of these metrics are up 2% on prior year.

3.3 Time of Use

We introduced 'Time of Use' pricing for all residential and small to medium businesses effective from 1 April 2020. ToU pricing is mandatory for all consumers on our DM1, DM3, DM7, ND1 and ND2 price plans, with a default option available for connections without a communicating smart meter, or if retailers are unable to comply with the data requirements. If this is the case, the retailer may apply for an exemption setting out the reasons they cannot provide the data and steps they are taking to address this. The prices have been set to be revenue neutral between those on the relevant ToU plan and those on the applicable default plan (e.g. between Residential Low User – Default and Residential Low User – Time of Use).

Introduction of ToU sets us up for the future by signalling to consumers when and how to efficiently use the network to reduce incremental costs as demand grows. In practical terms, it sends efficient pricing signals to consumers purchasing electric vehicles, solar panels, and batteries as to the realistic costs of and savings from these investments so they can determine when is best to charge, and whether the investments are efficient. It also means the structure is in place for when stronger price signals are required in the future.

Phasing of price changes

The ToU pricing structure will, over a five year period, have increasingly higher prices during peak times of the day when the network is more congested, and lower rates during off-peak times when there is plenty of capacity in the network. This phased approach has been taken to mitigate the impact upon consumers (in the event that retailers choose to pass the changes through), giving consumers time to respond to the pricing structure and adapt their behaviours, while also signalling what changes will be made in coming years.

We have increased the differential this year to approximately 2c between peak and off-peak. This indicates to consumers that consuming electricity off-peak may save us money compared to consuming it at peak times, and shares this benefit with consumers who consume off peak. Over time, we expect that within the ToU pricing structures, the fixed daily price will increase and the variable charges will decrease while still retaining a differential between peak and off-peak pricing.

Update on implementation

For the 2021 pricing year we approved full or partial exemptions from ToU pricing for 11 participant codes, out of a total of 25 participant codes trading on our network as at the start of the 2021 pricing year. These exemptions were approved for a variety of reasons, including retailers that were unable to provide time-sliced EIEP1 format data, and that were unable to access the required information from some MEPs. 28% of ICPs on our DM1, DM3, DM7, ND1 and ND2 price plans are currently on the ToU plan, with the balance on the default plan. We expect uptake to increase for FY22.

3.4 Residential Standard Plan

The Low Fixed Charge Regulations require us to offer a residential plan for consumers at their permanent place of residence, where the daily charge is no more than 15c per day (excluding GST). We may also offer a standard residential plan for consumers at their permanent place of residence with a different daily charge, provided that the charges under both plans are the same at 8,000kWh p.a.

To improve the cost reflectiveness of our pricing within the constraints of the Low Fixed Charge Regulations, we last year introduced a standard residential plan for consumers at their permanent place of residence. Residential connections using over 8,000kWh a year are able to move to this plan which has a higher daily price and a lower per kWh price, better reflecting their fair share of the fixed costs of running our network. 31% of residential consumers at their permanent place of residence have taken advantage of the new standard plan.

This year we have increased the fixed daily rate, but reduced the controlled and night rates to nil. This reflects that we currently have spare capacity outside of peak times, which can be utilised at little to no incremental cost. In future pricing years we expect fixed daily rates to continue to increase on this plan, while the uncontrolled variable rate will decrease.

The Government has indicated that it intends to phase out the Low Fixed Charge regulations. We expect this to begin from the 2023 pricing year, and that the DM1 and DM7 price plans will be amalgamated at the end of the phase-out period.

3.5 Rebalance fixed and variable prices

The majority of our costs are fixed in nature, meaning that they do not vary based on how much electricity our consumers use. This reflects the physical nature of our network, which is primarily made up of power poles, power lines, transformers, and substations. Investments to extend the network, replace assets, or create more capacity are made with a long term view of usually 40 years plus.

We are changing our pricing over time to better reflect the fixed cost nature of our business and to incentivise consumers to shift usage to times where there is spare capacity in the network. This has a number of benefits, including sharing the cost of the network more fairly across those who have access to the network, reducing the incremental cost to consume electricity, and reducing revenue risk. It also addresses the impact of flat to falling electricity consumption per connection, which is driven by consumers investing in more efficient appliances, and installing distributed generation and storage such as solar and batteries.

As part of this, we have this year increased the daily price for a number of price categories, and in most cases reduced the per kWh prices. Our focus this year has been on reducing controlled and night consumption prices, as this consumption is outside of our peaks and therefore drives little to no incremental costs.

We plan to continue to rebalance fixed and variable pricing over a 5 year period commencing from 2020-2021, to achieve a cost reflective outcome (within the constraints of the Low Fixed Charge Regulations which impose limits upon daily charges for some residential consumers). Our expected end point for mass market is for peak pricing to be around 10c/kWh (i.e. our LRMC to build new capacity), with off-peak pricing at nil, and shoulder pricing between those two points. The balance of our costs would be recouped through fixed charges, as these are the least-distorting revenue recovery method.

3.6 Large Commercial & Industrial

We have introduced new price category codes for the 2022 pricing year, to replace the current ND9 and ND10 price category codes which are currently used for large commercial consumers.

The current price category codes offer consumers with HHR metering a choice of a kWh based pricing option, or a demand based pricing option. However, a large number of these sites have dedicated transformers or connect at high voltage, and we are required to maintain a certain capacity to those sites irrespective of whether they utilise (and pay for) that capacity under the current pricing structures.

As such, to improve the cost reflectiveness of Large Commercial & Industrial pricing we have introduced 4 new price component codes:

Price Category Code	Description	Eligibility
LC1	Low Voltage - kWh Based	ICP is supplied from Northpower's low voltage network via a transformer which is owned by Northpower and shared with other ICPs.
LC2	Low Voltage - Capacity Based	
LC3	Dedicated Transformer	ICP is supplied from a transformer which is owned by Northpower and dedicated to the supply of the ICP.
LC4	High Voltage	ICP is supplied from Northpower's high voltage (11kV or higher) network.

The key change is that where a customer is supplied from a dedicated transformer, they will be charged based on the capacity supplied to them, irrespective of whether they use the full capacity. Similarly, where a customer is supplied from our HV network, they will be charged based on the capacity made available to them, based on the capacity of the customer-owned transformers that they install.

Consumers may change their capacity to reduce their lines charges, but if they exceed their capacity excess charges will apply. There will also not be any guarantee that excess capacity will be available for them to access.

3.7 Roadmap

We have prepared and published a roadmap outlining our plan to implement cost reflective pricing, and update it with our progress every twelve months. It is available on our website. This year we have:

- Replaced our large commercial and industrial price plans with new, more cost reflective pricing structures
- Continued to re-weight fixed and variable prices
- Increased the differential between peak and off-peak prices
- Replaced our billing system in order to implement Replacement Normalised billing, which we expect to increase uptake of ToU pricing by retailers
- Added distributed generators over 1MW to our Very Large Industrial consumer group
- Improved allocators in our Cost of Supply model

For the next 12 months our focus will be on:

- Increasing uptake of ToU pricing for residential and small to medium businesses
- Bedding in new Commercial and Industrial pricing structures
- Continue re-weighting fixed and variable pricing, and increasing peak/off-peak differentials
- Complete planning for the repeal of the Low Fixed Charge regulations
- Review incremental costs incurred in relation to Mass Market distributed generation and assess whether new pricing is required to recover these costs
- Review and update our Capital Contributions policy
- Review our Cost of Supply model with a view to restructuring it using the approach set out by the EA in its 2019 Practice Note

4 Changes to Pricing Methodology in 2021-2022

We have made some changes to our pricing methodology for 2021-2022:

We have added distributed generation with capacity of 1MW+ to the Very Large Industrial consumer group. This means these consumers will now be on-charged our incremental costs for connecting these sites, such as dedicated assets. We expect charges for these sites to increase as we confirm the incremental costs that apply.

We have changed the allocator that we use to allocate non-asset related fixed overhead costs. These were previously allocated using an arbitrary estimate, and will now be allocated on the basis of customer peak demand.

5 Target Revenue

We are targeting to recover $73.2m through prices for the year ending 31 March 2022, which covers the following components. These costs are forecast to be incurred to operate and maintain the electricity network.

Type	Component	2021 $m	2022 $m
Distribution	Operating Expenditure	27.0	28.4
	Depreciation	11.2	11.2
	Regulatory Tax Allowance	3.3	3.7
	Revaluations	(5.4)	(5.9)
	Other Regulated Income	(0.4)	(0.7)
	Return on Investment	17.5	18.8
Pass through	Transmission	18.4	17.2
	Rates	0.1	0.1
	Levies	0.2	0.2
Total		**72.0**	**73.2**

The target revenue is +$1.2m up on FY21, and is shown including the discount to be paid during the pricing year (i.e. the target revenue net of the discount will be $61.5m). The discount is included in the ROI for the purposes of applying the BBM framework.

6 Consumer Groups

We have categorised connections to our network into two groups, in order to allocate the target revenue to these groups as part of the price setting process. The groups have been developed based on the nature of the service that they receive and whether they have assets dedicated to their supply.

Consumer Group	Description
VLI	Very Large Industrial ("VLI") consumers have significant Northpower assets dedicated to their site. In most cases they have a dedicated feeder supplying their site from a Northpower substation, and often have dedicated backup feeders to provide N-1 security. They receive a higher level of service reflecting their reliance on electricity to operate significant sized and often critical industrial processes.
Mass Market	Mass Market includes all other sites including homes and businesses. These sites are supplied via assets which are shared across many consumers, and generally have no or limited assets dedicated to their supply.

Customers are allocated to the above groups based on their method of connection to the network (i.e. consumers with dedicated feeders or significant Northpower assets are allocated to VLI) and reflected by their price category code. The allocations are made in consultation with the consumer or retailer usually based on their request, to balance consumer and network outcomes.

7 Allocation of Target Revenue to Consumer Groups

We use our Cost of Supply model ("CoS model") to allocate the costs of owning and operating the distribution network to the consumer groups described in the previous section, to determine how much of the target revenue we intend to recover from each consumer group. The allocators reflect how the different consumer groups drive the cost components.

7.1 Transmission

Transmission is made up of Transpower's charges for access to the national grid, and Avoided Cost of Transmission ("ACOT"). ACOT is paid to generators who inject electricity directly into the Northpower network, and through doing so reduce the charges that we would otherwise pay to Transpower.

Transpower's charges consist of two costs, 'interconnection' and 'connection'. Interconnection represents our contribution to the National Grid, and connection is the charges for assets located at the Grid Exit Point through which we connect to the National Grid.

Interconnection

Our contribution to the National Grid is charged by Transpower based on our share of the total load in the Upper North Island during the 100 half hour periods with the highest load for the prior 12-month period. We calculate the load of the different consumer groups during the same half hour periods to allocate the Transpower interconnection cost.

We also pay ACOT to eligible generators who inject into the Northpower network during the 100 highest peaks, calculated as the amount that we would have otherwise paid to Transpower. ACOT expenses are allocated to the consumer groups using the same methodology as Interconnection, and are included in the table below.

Consumer Group	Contribution to RCPD (kW)	%	Cost ($m)
VLI	40,490	27%	4.0
Mass Market	110,115	73%	10.8
Total	**150,605**	**100%**	**14.8**

The cost of interconnection is down ($1.4m) compared to the prior year, mainly driven by a VLI consumer who had a materially lower load during the 100 highest half hour periods. Mass Market load increased by 5MW, which drove an increase in interconnection costs for this consumer group of $0.4m

Connection

Transpower also charges us for our share of the costs for the grid exit points ("GXPs") that we use, based on the value of the assets and our usage of those assets. These charges have increased by 9% compared to the prior year.

Connection charges are allocated to the consumer groups based on their contribution to the peak demand at each GXP, calculated as the average of the 12 highest half hour periods for the Capacity Measurement Period (for 2022 pricing, the period from September 2019 to August 2020).

Consumer Group	Contribution to peak demand (kW)	%	Cost ($m)
VLI	64,125	36%	1.5
Mass Market	114,845	64%	1.0
Total	**178,970**	**100%**	**2.5**

We connect to Transpower's national grid at three different GXPs; Bream Bay, Maungatapere, and Maungaturoto. The costs of each GXP have been attributed separately to each consumer group, and then added together. As such, the percentage of a consumers group's contribution to peak demand may vary from the percentage of cost allocated to them.

7.2 Operating Expenditure

Asset Costs

The costs to maintain and repair network assets are allocated to consumer groups based on the degree to which each of the consumer groups use or have access to the underlying assets. Assets have been allocated using the allocators below:

Asset	Allocator	VLI	Mass Market
Dedicated sub-trans mission (33kV) lines/ cables	Customer allocation	100%	0%
Sub-transmission (33kV) lines/cables	Peak demand	2%	98%
Zone substations	Peak demand	15%	85%
Distribution substations and transformers	kVA	6%	94%
Distribution and LV lines	Length	0%	100%
Distribution and LV cables	Length	0%	100%
Distribution switchgear	Peak demand	15%	85%
Other network assets	Assessment	0%	100%
Non-network assets	Peak demand	39%	61%
Weighted Total	**Asset Value**	**6%**	**94%**

Preventative maintenance is allocated based on the weighted total value of assets utilised by the consumer group, as all assets require periodic maintenance. Reactive maintenance (i.e. fault call outs) is primarily driven by incidents which affect power lines and poles (for example trees falling on lines, cars hitting poles, diggers hitting buried cables) and as such is allocated based upon the value of lines/cables allocated.

Operational costs relating to running and maintaining the core assets in our network are allocated based on the cost allocator assigned to the asset type they support. For example, substation related running costs are assigned based on peak demand, which is also used to allocate substation asset costs.

Non Asset Costs

Non Asset costs are the overhead costs to operate and maintain the network. They include the engineers who monitor the performance of the network, design extensions and upgrades, and plan for the future. It also includes the customer services teams, operations teams who monitor the network 24/7 and manage outages, health and safety, and billing functions. From this year, these costs will be allocated based on consumer group’s peak demand on the network.

Return on Investment, Depreciation, Regulatory Tax Allowance, and Revaluations

These costs are where we recover the depreciation on the assets which make up our network, the cost of tax, and a return on our investment. This component is important because it allows us to replace assets as they reach the end of their lives, and to invest in new assets as the network expands, in new technology, and improve the performance and reliability of the network.

These costs relate to the underlying network assets, and are therefore allocated to the consumer groups based on the total assets that each consumer group uses as described above.

7.3 Total Target Revenue allocated to each Consumer Group

Using the allocators described above, we allocate the $73.2m target revenue to each of the consumer groups. The target amount that we intend to recover from each group is outlined below:

	Component	VLI $m	Mass Market $m	Total $m
Distribution	Operating Expenditure	6.1	22.3	28.4
	Depreciation	0.7	10.6	11.3
	Regulatory Tax Allowance	0.2	3.5	3.7
	Revaluations	(0.3)	(5.5)	(5.9)
	Other Regulated Income	0.0	(0.7)	(0.7)
	Return on Investment	1.1	17.8	18.8
Pass through	Transmission	5.5	11.8	17.2
	Rates	0.0	0.1	0.1
	Levies	0.1	0.1	0.2
Total		**13.3**	**59.9**	**73.2**

8 Price Setting Process

The following sections explain how we set our prices to recover the Target Revenue allocated to each consumer group. It explains what types of prices are used, and how the prices are set.

8.1 Very Large Industrial

We offer non-standard pricing to very large industrial consumers who would like us to own and operate assets of significant value which are dedicated to their supply. We currently have six consumers in this consumer group, of whom one has a non-standard contract and five operate under their retailer's Use of System Agreement. Consumers in this group can choose if they want to be on a non-standard contract or billed via a retailer.

The pricing is based on the assets that the customer uses and the services that they receive, to ensure Northpower recovers the costs of the dedicated and shared assets, an appropriate return on investment, and the associated operating and maintenance costs. Transmission costs are passed through in a transparent manner.

The revenue target for these consumers is $13.3m for 2021-2022. We forecast that revenue from these consumers will be $8.3m, as we are phasing the impact of changing the allocator for non-asset related costs over a 5 year period to mitigate the impact on these consumers. Of these amounts, our target revenue from non-standard contracts is $7.3m and our forecast revenue from non-standard contracts is $3.8m

VLI prices have changed compared to the prior year due to the change in allocator (+$4.6m), and changes in transmission costs which are passed through transparently based on each customer's usage ($1.7m reduction).

8.2 Mass Market

Types of Prices

The types of prices used across our price categories are described below. Only some of these components apply to each price category.

Price Component	Units	Description
Daily price	$/day	Daily price is applied to the number of days each ICP is connected to our network.
Volume	$/kWh	Volume price applied to the volume of electricity distributed to each ICP. The rate may vary depending on the price category, for example uncontrolled (available 24 hours a day), controlled 18 (available 18 hours a day), or controlled 22 (available 22 hours a day).
Capacity	$/kVa/day	The capacity of the ICP's connection to the Northpower network as at the last day of the month, as determined by Northpower. In determining the capacity, Northpower will take into account the below factors, in addition to any other factors which it considers relevant to the ICP: **Low Voltage:** Fuse Capacity **Transformer:** Transformer Capacity **High Voltage:** Customer's Transformer Capacity
Demand	$/kVa/day	The average of the ICP's 10 highest half hour kVA demands between 7am and 10pm (including weekends and public holidays) calculated across the month.
Excess Demand	$/kVa/day	The difference between the anytime maximum demand (i.e. single highest half hour kVA demand) and the ICP's capacity, where the consumer's anytime maximum demand is greater than the capacity. Charge is calculated as the (highest half hour period demand (in kVA) during the month less capacity) x rate x days in month.
Power Factor	$/kVAr/day	The power factor amount is determined each month where a consumer's power factor is less than 0.95 lagging. This power factor amount (kVAr) is represented by twice the largest difference between the consumer's kVArh recorded in any one half-hour period and the kWh demand divided by three recorded in the same half-hour period, during each month.
Streetlights	$/fixture/day	Fixture daily price is multiplied by the number of fixtures and number of days.

We have a number of Mass Market price categories to comply with regulations and meet the needs of different groups of consumers. For residential and small to medium business plans we have a ToU plan, and a default option which applies when the customer does not have a communicating smart meter or the retailer has a valid approved exemption.

Consumer Group Subset	Price Category Code	Description
Residential	DM1 DM1-ToU	Residential Low User – Principal Place of Residence
	DM3 DM3-ToU	Residential – Non-Principal Place of Residence
	DM7 DM7-ToU	Residential Standard - Principal Place of Residence
General	ND1 ND1-ToU	Up to 70kVA - 100A or less
	ND2 ND2-ToU	Greater than 70kVA (CT metering)
	ND5	Irrigation and pumps
	ND6	Unmetered 24 Hour
	ND12	Builders Temporary Supply
Streetlights	H	Daily Price
	26-1	Demand band 1
	26-2	Demand band 2
	26-3	Demand band 3
	26-4	Demand band 4
	26-5	Demand band 5
Large Commercial & Industrial	LC1	Low Voltage – kWh Based
	LC2	Low Voltage – Capacity Based
	LC3	Dedicated Transformer
	LC4	High Voltage

Our process to set prices is to forecast the expected volumes for each price category and component, and adjust the prices to achieve the balance of the revenue target (after VLI forecast revenue is subtracted). Our pricing strategy informs our approach to making these changes.

The key changes for this year are to:

- Increase the daily price for some plans, and in most cases to reduce the variable prices, to better reflect the fixed cost nature of our cost base.
- Introduce new price category codes LC1, LC2, LC3, and LC4, to replace our previous large commercial and industrial pricing plans (ND9 and ND10).

The Low Fixed Charge Regulations require us to offer residential consumers a price option at their primary place of residence with a fixed price of no more than 15c per day (excluding GST) and where the sum of the annual fixed and volume charges on that price option equals any other primary price of residence price option for residential consumers using 8,000kWh per annum. Our DM1 and DM7 price categories comply with these regulations.

Mass Market prices have changed compared to the prior year due to the change in target revenue for this consumer group, due to the implementation of cost reflective pricing structures outlined above, and the continued rebalancing of pricing.

8.3 Distributed Generation

We have added distributed generators with capacity of 1MW+ to our Very Large Industrial consumer group this year, which has resulted in price changes for affected consumers (where we are not limited by contractual obligations) of ~$30k. We do not currently charge distributed generators with lower levels of capacity to use our network to convey electricity to their customers, but we expect that we will need to recover our incremental costs driven by the distributed generation from these customers in the future.

We pay ACOT of $0.9m to two large scale generators under Part 6 of the Electricity Industry Participation Code. This involves assessing the generator's average output at the time of the 100 highest UNI peaks, to calculate the Transpower interconnection cost saved due to the generator injecting into our network at the time of those peaks.

We only pay ACOT where required to do so under the Electricity Code. We do not pay ACOT to owners of small scale generators below 10kWh, as most small scale generation is solar and therefore the generation is unlikely to coincide with the UNI 100 highest peaks and reduce the Transpower transmission cost as a result.

9 Responsibilities to Very Large Industrial consumers

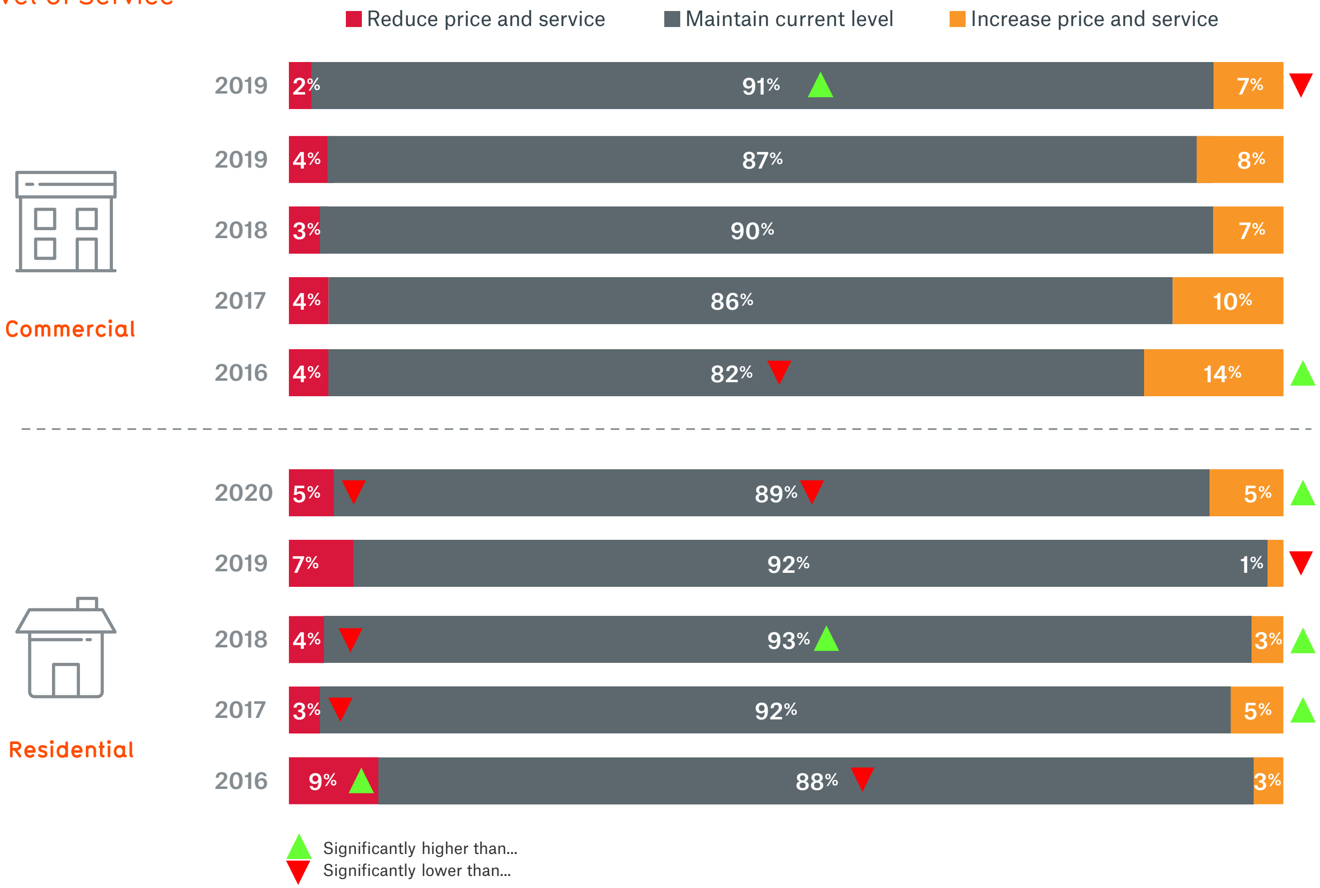
While only one of our VLI consumers is on a non-standard contract, our obligations and responsibilities to that consumer are broadly the same as other consumers including VLI consumers. The key difference is that VLI consumers including those on non-standard contracts are able to input into their supply configuration, and as such they sometimes opt to duplicate assets to increase security of supply. For example, some VLI sites elect to have two incoming feeders, each capable of supplying the entire load for the site, to ensure they have a backup if one feeder fails. They also often have assets which are dedicated to their supply, such as dedicated feeders.

The non-standard pricing offered to our VLI consumers reflects the assets which they use, and as such their contribution towards target revenue covers the additional cost of the duplication of assets to improve security of supply.

10 Consultation

We consult with a range of stakeholders including consumers, retailers, and the Northpower Electric Power Trust on behalf of our consumer owners, on a range of issues including their views on pricing, quality, and the desirable level of trade-off between these two factors. For example, the below question is from our 2020 annual survey of consumers. The majority of consumers are satisfied with the current levels of service and would prefer that these are maintained rather than the price level adjusted. We factor these views into our expenditure planning, which flow into our target revenue and ultimately prices.

Preferred Level of Service (1)(2)



NOTES:

1. *Sample: 2016 Total n=400, Commercial n=100, Residential n=300; 2017 Total n=400, Commercial n=100, Residential n=300; 2018 Total n=400, Commercial n=100, Residential n=300; 2019 Total n=403, Commercial n=101, Residential n=302; 2020 Total n=397, Commercial n=95; Residential n=302*
2. *PV4, Northpower's level of service is based on reliability of supply, supply quality such as avoiding surges and spikes, and response times to faults. Changes in service levels might require changes in price. If you had to choose which one of the following best describes what you prefer?*

We also consulted extensively with retailers on the changes made to 2021-2022 pricing.

Appendix 1: Proportion of Target Revenue by Price Component

Price Component Code	%	Price Component Code	%
02	12.0%	1550	0.3%
03	0.7%	1551	0.9%
04	7.6%	1552	0.3%
05	2.5%	26-1	0.1%
06	2.3%	26-2	0.0%
07	0.1%	26-3	0.1%
11	0.1%	26-4	0.0%
12	0.0%	26-5	0.3%
19	0.0%	200RP	0.0%
25	0.0%	210CAP	1.4%
32	2.8%	210EXD	0.0%
33	6.1%	210PKD	0.0%
46	0.0%	210RP	0.0%
47	0.0%	220CAP	4.5%
53	0.1%	220EXD	0.0%
55	0.2%	220PKD	0.0%
92	0.0%	220RP	0.0%
93	0.0%	230CAP	0.1%
201	0.0%	230EXD	0.0%
211	0.0%	230PKD	0.0%
221	0.0%	230RP	0.0%
231	0.0%	A	4.5%
1050	2.2%	ATOU	3.7%
1051	5.1%	B	0.5%
1052	2.4%	BTOU	0.4%
1106	0.0%	C	1.3%
1107	0.0%	CTOU	1.1%

Price Component Code	%	Price Component Code	%
1150	0.1%	G	0.1%
1151	0.3%	H	0.5%
1152	0.1%	HHHVC	0.0%
1206	0.0%	HHLVC	0.1%
1207	0.0%	HHLVT	0.2%
1250	1.4%	HHLVV	0.1%
1251	3.2%	IND	11.3%
1252	1.6%	K	3.9%
1350	1.1%	KTOU	3.2%
1351	2.8%	P	0.1%
1352	1.1%	T	0.2%
1450	0.5%	W	1.4%
1451	1.3%	WTOU	1.2%
1452	0.5%		

Appendix 2: Glossary

Term	Definition
AMD	Anytime Maximum Demand. The highest half-hour demand, usually in kVA, during a one year period.
Avoided Cost of Transmission ("ACOT")	A reduction in the transmission costs payable by distributors to Transpower (usually in the context of embedded generation).
Code	Electricity Industry Participation Code 2010 and subsequent amendments.
Commission	Commerce Commission
Consumer	A person or an entity whose electricity installation is connected to the electricity network.
Consumer Group	A broad category of electricity consumers.
Controlled	An option where consumers elect to have part of their electricity supply subject to interruption at Northpower's discretion. The most common example is control of electrically heated hot water.
Demand	Electricity load, measured in either kW or kVA, usually averaged over a half-hour period.
Distributor (EDB)	An entity other than Transpower which owns an electricity network other than an embedded network. Often denoted as an Electricity Distribution Business (EDB).
Distributed generation (DG)	An electricity generator connected directly to an electricity distribution network (rather than to the transmission grid). Also called Embedded Generation.
EDIDD	Electricity Distribution Information Disclosure Determination 2012 published by the Commerce Commission as Decision NZCC 22 dated 1 October 2012, as subsequently amended.
Electricity Industry Act (EIA)	Electricity Industry Act 2010.
Half-hour metered	An ICP with metering that records electricity consumption in half-hour intervals.
ICP	Installation Control Point. An individual connection to an electricity distribution network.
kVA	Kilovolt-amp. Measure of total apparent power.
kVAr	Reactive power.
kW	Kilowatt. Measure of true power.

Appendix 2: Glossary

Term	Definition
kWh	Kilowatt-hour. Rate of energy flow.
Low Fixed Charge Regulations	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Non-principal place of residence	A residential premise that is not the principal place of the consumer in the context of clause 3 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Non-standard contract	A contract that is not a standard contract in terms of the EDIDD 2012. (Refer to definition of Standard contract below.)
Point of Connection (PoC)	The connection between the transmission grid and a distribution network. Also called a Grid Exit Point (GXP).
Power factor	kW/kVA
Pricing Principles	The distribution pricing principles published by the former Electricity Commission in 2010, adopted by the Electricity Authority, and amended from time to time.
Principal Place of Residence	In the context of clause 3 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Regional Coincident Peak Demand (RCPD)	The average demand at the times of the hundred highest half-hour regional demands.
Residential Consumer	A consumer at a residential ICP which satisfies the definition of “domestic premises” in Section 5 of the Electricity Industry Act 2010.
Standard contract	EDIDD 2012 defines a standard contract as one where the price for electricity line services is determined solely by reference to a publicly disclosed schedule of prescribed terms and conditions, or a contract which covers at least five persons, none of which is a related party to the EDB or each other.
TPM	Transmission Pricing Methodology – the methodology defined in accordance with Part F (subpart 4) of the Code by which transmission prices are allocated to participants with connections to the national electricity grid.
Transmission grid	The national electricity grid owned and operated by Transpower.
Upper North Island (UNI)	The area of the North Island north of Huntly.

Appendix 3: Consistency with Electricity Authority Pricing Principles

Pricing Principle	Consistency of Northpower pricing methodology
(a) Prices are to signal the economic costs of service provision, including by: i. being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs); ii. reflecting the impacts of network use on economic costs; iii. reflecting differences in network service provided to (or by) consumers; and iv. encouraging efficient network alternatives.	Our approach to setting prices is: 2. 1) we allocate the costs of providing our services to consumer groups, based on the assets which are dedicated to them, the degree to which they share common assets, and the degree to which they drive the costs we incur to run the network. 3. 2) we set prices for the consumer groups to signal the cost of providing that service. This approach does not yet incorporate the approach set out in the EA's 2019 practice note, but we expect to incorporate this into our Pricing Methodology for 2022-2023. This approach will inform the end prices that we get to as we phase pricing changes over a five year period. This approach has been taken to mitigate the impact on consumers. **Subsidy free** The costs that we incur can be categorised as: • **Incremental costs:** these are costs incurred specifically for that customer, for example the cost of dedicated feeders for a VLI consumer. • **Shared costs:** these are costs which would still be incurred if any consumer group existed on a standalone basis, but when multiple consumer groups exist these costs can be shared. To be subsidy free, our forecast revenue for each consumer group should fall between avoidable costs (i.e. incremental costs) and standalone costs (incremental plus the full shared costs). We are forecasting to recover our incremental costs plus a portion of the shared costs from each consumer group, and therefore our pricing meets the subsidy free test in the Distribution Pricing Practice Note. **Reflecting the impacts of network use on economic costs** Northpower's costs are largely fixed, driven by the physical footprint of the network, and long term nature of investment decisions. Variable costs are largely limited to the Transpower transmission charges. ***Mass Market*** Our Mass Market pricing has historically had a high per kWh rate and low daily connection rate, which does not correlate closely to our costs drivers. To address this we have this year: • Increased the differential between peak and off-peak pricing to approximately 2c/kWh. We expect the end point to be approximately 10c/kWh, based on our long run marginal cost (LRMC). • Continued rebalancing our fixed and variable prices, within the limitations of the Low Fixed Charge Regulations. This year we have increased fixed rates and reduced variable rates, with a focus on reducing controlled and night rates. The consumption to which these rates relate occurs outside of network peaks, and therefore there is effectively no incremental cost to provide this consumption. As such, in most cases we have reduced the price to 1c or in some cases nil, except where the Low Fixed Charge Regulations prevent us from recovering the balance in the least distortionary way (i.e. through the fixed charge). • Introduced new Large Commercial & Industrial plans, which more closely reflect our cost structure. In particular, customers with a dedicated transformer will be charged based on the capacity of their connection to the network (irrespective of their utilisation of that connection), and customers who connect at high voltage will have differentiated pricing to reflect that we do incur the cost of providing them with a dedicated transformer.

Appendix 3: Consistency with Electricity Authority Pricing Principles

Pricing Principle	Consistency of Northpower pricing methodology
	We have not specifically addressed density and distance from the GXP through location pricing due to complexity and transaction costs, we note that these are to some extent inherently reflected in our price category codes. For example, business prices on our network tend to be higher than residential because of the large number of farms which are further from the GXP and in less populated areas. Another example is our non-principal place of residence dwellings plan, which caters for holiday homes which also tend to be in less populated areas further from the GXP. ***Very Large Industrial*** Our pricing for VLI consumers is set based on the costs allocated to them, and therefore there is a direct correlation between their prices and our cost to provide the service to them. If they vary the service they require or the way they use our network, and this changes our costs, this has a direct impact on their costs. For example, the transmission costs, and the costs of assets dedicated to their supply, are passed through directly. Costs of shared assets and network management costs are passed through based on an appropriate cost driver. We note there is one VLI consumer for whom our pricing is limited by a non-standard contract that was struck prior to the implementation of the current regulatory regime. **Differences in network services** ***Mass Market*** Our Mass Market price category codes reflect the service that consumers receive: • We have different pricing depending on the capacity of the customer's connection to the network, as this is a key cost driver for us. We have this year expanded on this, with differentiated pricing for if you connect at high voltage so we do not need to supply a transformer. • We offer lower per kWh rates for supplies where the consumer agrees that we may control the load for a period during the day to manage load on the network. For us this predominantly relates to hot water load control, and most residential dwellings in our network that have electric hot water have a ripple controller installed. These consumers receive a lower price in relation to their controlled load, reflecting that there are little to no incremental costs to provide this supply outside of network peak periods.

Appendix 3: Consistency with Electricity Authority Pricing Principles

Pricing Principle	Consistency of Northpower pricing methodology
	Very Large Industrial Our VLI pricing is a direct charge through of the costs we incur to provide them with the service, as such it inherently reflects the differences in the service they receive. For example, most VLI consumers have dedicated feeders, some with N-1 security. The costs of the assets are charged back to them, reflecting the differentiated service they receive in terms of dedicated assets and increased security of supply. These consumers also receive a higher level of personalised service compared to the average consumer. For example, they have direct access to our 24/7 control room in the event of an outage, receiving direct updates, control room to control room coordination, and priority restoration. Another example is that we liaise around Northpower and Transpower maintenance schedules to avoid their busy periods and where possible to coincide with planned maintenance windows. The allocation of non-asset related fixed overhead costs based on customer peak (as opposed to for example the number of ICPs) reflects that these customers require a higher level of service commiserate with their larger load on the network. **Encouraging efficient network alternatives** ***Distributed Generation/Storage*** We think that the current risk from our pricing is not that it doesn't do enough to encourage efficient network alternatives, but that in some scenarios it may subsidise inefficient network alternatives. This is largely driven by the Low Fixed Charge Regulations, which limit the daily connection charges that we can charge for most connections on our network to levels well below cost. If a network prices its daily connection prices below its actual fixed costs to connect a consumer to the network, and recoups the balance of its fixed costs through variable charges, this creates an incentive for the consumer to invest in distributed generation and distributed storage to reduce their variable charges. The result is that the network receives less in revenues than its costs to provide the connection, and other consumers have to pay the shortfall through their variable charges. It also means that the electricity network is under-utilised, whilst the consumer has purchased equipment to duplicate the electricity network functions, which is inefficient. We are rebalancing our fixed and variable prices to address this (within the limitations of the Low Fixed Charge Regulations). Whilst the rebalancing will take place over a number of years to mitigate the impact on consumers, we are also signalling the changes to consumers so that they can make educated decisions to invest in network alternatives. This year we have increased fixed charges and reduced variable charges for controlled and night, reflecting our incremental costs to provide consumption at these times are effectively nil. We have also increased the differential between peak and off-peak to approximately 2c/kWh, and expect to continue to increase this differential to approximately 10c/kWh based on our current LRMC. ***Demand Response/Interruptible demand*** As described above, we offer discounted pricing for controlled load and Time of Use pricing. These price signals incentivise consumers to shift load and adjust their demand at certain times of the day when we might experience congestion, in order to avoid investment in transmission or distribution upgrades.
(b) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.	We are working to achieve this outcome by reducing variable charges to reflect our LRMC, and increasing fixed charges to recover the shortfall in the method that least distorts network use. We are phasing this change over a 5 year period to mitigate the impact on consumers.

Appendix 3: Consistency with Electricity Authority Pricing Principles

Pricing Principle	Consistency of Northpower pricing methodology
(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to: i. reflect the economic value of services; and ii. enable price/quality trade-offs.	**Reflect the economic value of services** Our VLI consumers are able to negotiate directly with us to achieve prices which are cost reflective and fair to both parties, and as such are unlikely to curtail demand, disconnect, or not connect due to facing standard prices. Mass Market consumers often currently receive lower daily and higher variable prices which incentivise them to inefficiently curtail demand, for example by acquiring further electrical assets to construct distributed generation or storage. We are phasing in prices to send appropriate signals regarding this over a period of time. For larger commercial and industrial consumers who might disconnect or not connect in the first place if faced with standard pricing, we offer capacity based charging which reflects the service they receive. **Price/quality trade offs** Our VLI consumers have individually negotiated arrangements, where they can determine the various service quality aspects of their connection and their pricing is adjusted accordingly based on the cost to us to provide that service. For example, some VLI consumers opt to have dedicated feeders so they have guaranteed capacity, to underground their feeders to increase security of supply, and to have multiple feeders to provide N-1 security. Some opt to connect at 33kV and provide their own transformers, whilst others opt for Northpower to provide and maintain transformers. It is practically difficult to provide Mass Market consumers with options to vary their level of service quality (reliability, resilience, etc.) at an individual or price plan level, as they are using shared assets. However our pricing does, where practical, include options which relate to service quality, for example consumers can opt for a controlled 18 hour or night only price plan where they receive a lower price in exchange for reduced availability of supply. We are seeing some electric vehicle owners take advantage of lower priced electricity in exchange for reducing their availability hours, in addition to the usual hot water load control. We do survey consumers to understand their views on price, service levels, and the trade-off between these factors. This is factored into our price setting processes.
(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.	**Transparency** Our development of pricing is transparent, in that we describe our approach and the strategic changes we are making to pricing in our Pricing Methodology. We also communicate key changes and messaging as part of our public disclosure of pricing. **Transaction costs, consumer impacts, and uptake incentives** Our pricing is not yet perfectly cost reflective, because we are phasing price changes over a number of years in order to mitigate the impact on consumers. We have also made some decisions to not be perfectly cost reflective due to transaction costs, for example: • We have aligned our Peak, Shoulder, and Off-Peak time periods with Top Energy to create one standard pricing structure for residential and small to medium business across Northland. While this is not perfectly cost reflective as we have slightly different peaks, it mitigates the impact on and creates efficiencies for retailers. • We have not implemented locational pricing within our network as we consider the transaction costs currently outweigh the benefits, noting that the regional nature of EDBs already implicitly creates locational pricing across NZ.

Schedule 17: Certification for Year-beginning Disclosures

(Distribution Pricing Methodology for the year commencing 1 April 2021)

Clause 2.9.1

We, **Mark Trigg**, and **Richard Booth**, being Directors of Northpower Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Northpower Limited prepared for the purposes of clauses 2.4.1 to 2.4.5 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

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Date: 21 February 2021

Northpower